COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

***Ex Parte:* In the matter of**	**§**	
considering requirements relating	**§**	
to wires charges pursuant to the	**§**	**Case No. PUE-2001-00306**
Virginia Electric Utility	**§**	
Restructuring Act	**§**	

Direct Testimony and Exhibits of

Jeffry Pollock

On behalf of the

Virginia Committee for Fair Utility Rates (VCFUR)

August 2002

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

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Direct Testimony of Jeffry Pollock

Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 1215 Fern Ridge Parkway, Suite 208; St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and am employed by BAI.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A These are described in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Virginia Committee for Fair Utility Rates (VCFUR). The members of VCFUR are retail customers of Dominion Virginia Power (DVP). These customers purchase substantial quantities of electricity under Rate Schedule GS-4.

Summary of Testimony and Recommendations

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to comment on the methodology used to derive the market price of generation, which is used to calculate the proposed wires charges. Though my testimony is focused primarily on the analysis submitted by DVP, most of the same comments would also apply to AEP Virginia (AEP).

Q WHAT ARE YOUR SPECIFIC CRITICISMS OF THE METHODOLOGY PROPOSED BY DVP TO QUANTIFY GENERATION MARKET PRICES?

A Generation market prices are a key element in determining wires charges. They also determine the future revenue stream, and hence the value, of DVP's generation assets.

DVP's use of wholesale market prices understates the value of its generation fleet. This is inconsistent with the purpose of the wires charges, which along with capped rates for bundled service, is to recover positive net stranded costs associated with *retail* competition. By relying on a wholesale, rather than a *retail*, paradigm, DVP's methodology ignores the cost that competitive service providers (CSP) must incur in order to compete for *retail* business within the Commonwealth.

The future revenue stream will also depend on the nature of the various markets in which DVP's generation fleet will be deployed. Even if it were appropriate to use wholesale commodity prices to value DVP's generation assets, it would be inappropriate to use only one type of wholesale market (i.e., long-term forward energy strip contracts). Relying solely on one type of market ignores the existence of other wholesale markets, such as short-term (i.e., hourly, daily) energy, short-term capacity and ancillary services. It further ignores the fact that a diverse generation fleet can provide other value-added services, such as shaping and risk management. Participation in these other wholesale markets, along with the provision of value-added services, would potentially increase the future revenue stream associated with DVP's generation assets, thus reducing the wires charge.

DVP's analysis further ignores the value of capacity required to maintain system reliability. New generation capacity must be added to maintain a reasonable reserve margin. It is axiomatic that, where additional capacity is needed to meet projected demand, and absent market power, generation prices should reflect the incremental cost of new generation capacity. The market value used by DVP in developing the proposed wires charges, however, would not support the entry of such new generation.

Further, using forward wholesale energy prices is not required to enable DVP to recover just and reasonable net stranded costs. On the contrary, the use of such prices will allow DVP to over-recover stranded costs, and it will ensure that there will be no meaningful *retail* competition until at least July 1, 2007, when DVP is no longer subject to capped rates. Imposing wires charges in a manner that will result in little or no competition would be wasting the opportunity now available to determine whether *retail* customer choice can be viable when the capped rates are lifted.

Given that DVP has understated generation market prices, its proposal to deduct transmission and ancillary service charges should be rejected. DVP would recover any such costs – if they existed – in the overstated wires charges that result from understating its generation market prices. Further, any such additional transmission and ancillary service charges, if incurred by DVP, would be fully recovered if DVP were operating in a Regional Transmission Entity (RTE) because in an RTE environment transmission rate pancaking would be eliminated. DVP would not incur any additional unrecovered transmission costs associated with displaced sales. Retail customers should not be prevented from shopping just because the utilities failed to join an RTE on or before January 1, 2001.

Q WHAT ACTION SHOULD THE COMMISSION TAKE IN THIS PROCEEDING?

A DVP's proposed market prices and, thus, wires charges should be rejected. The Commission should require DVP and other utilities to project market prices at the *retail* level. That is, the prices should include costs that must be incurred by CSPs in order to successfully compete for *retail* business, recover their costs, and provide some margin. If the Commission requires DVP and other utilities to project market prices at the *retail* level, such prices will include the value of capacity needed to meet reliability needs. Should the Commission elect to rely on a wholesale, rather than a *retail*, market price projection, however, then additional capacity costs should be imputed so that the projected price is at least equal to the incremental cost of new generation capacity. This adjustment would reflect the economic reality that in capacity constrained markets prices must be sufficient to support the entry of new generation capacity. DVP's current and projected reserve margins clearly demonstrate that new generation capacity is needed in order to maintain system reliability.

No deductions from the projected market price should be made because the use of wholesale forward prices alone will enable DVP to over-recover its net stranded costs.

Finally, the Commission should docket a proceeding to quantify the stranded costs of each regulated electric utility that is either proposing, or has previously implemented, a wires charge. Should the Commission find that a utility has no stranded costs, then there would be no justification for imposing wires charges.

Wholesale vs. Retail Paradigm

Q WHY IS IT INAPPROPRIATE TO RELY ON WHOLESALE MARKETS TO DETERMINE PROJECTED MARKET PRICES FOR GENERATION?

A Reliance on wholesale markets to determine projected market prices for generation is inappropriate for several reasons. First, it is inconsistent to compare *wholesale* market prices with *retail* capped generation rates in order to calculate wires charges to be imposed upon *retail* customers. Second, it restrains potential Competitive Service Providers (CSPs) from entering *retail* markets in Virginia. Third, because there can never be a "negative" wires charge, it allows utilities to over-recover their just and reasonable net stranded costs.

Q PLEASE ELABORATE ON THE INCONSISTENCY BETWEEN THE USE OF A WHOLESALE PROXY TO COMPARE WITH CAPPED GENERATION RATES TO CALCULATE WIRES CHARGES IMPOSED ON RETAIL CUSTOMERS.

A Fundamentally, wires charges are imposed during a transition to *retail* competition. Until there is *retail* competition, incumbent electric utilities will not have stranded costs. The wires charge is the difference between an incumbent electric utility's capped unbundled rate for generation and the projected market prices for generation, as determined by the Commission. Because an incumbent electric utility's embedded generation cost is stated at *retail*, the only valid measure of the projected market price for generation would be the *retail* market value. Using a wholesale proxy to quantify a *retail* value would be like comparing apples and oranges.

Q WHY DO YOU CONTEND THAT USING A WHOLESALE PROXY FOR DETERMINING THE PROJECTED MARKET PRICES FOR GENERATION WOULD CONSTITUTE A BARRIER TO ENTRY BY POTENTIAL CSPs?

A CSPs will not enter the *retail* business in the Commonwealth unless they can provide a reliable and cost-effective supply of electricity that will enable the CSP to both recover its legitimate costs and to provide a reasonable return to its shareholders. Using a wholesale proxy to set the wires charge would in effect force CSPs to compete against a wholesale price. By definition, the wholesale price represents a CSP's cost to purchase generation services.

Although purchased power is the most significant cost to be incurred by a CSP, the CSP will also incur additional costs for marketing, back office functions and administration. Prior testimony submitted in this docket has indicated that these other costs are not trivial. The point is that CSPs cannot reasonably expect to recover their costs and earn a profit by selling *retail* electricity at less than the wholesale price.

Other parties previously have recognized this fundamental economic problem. For example, the Commission Staff concluded that:

> "Accordingly, competitive suppliers must be able to offer electric generation services to customers at rates that, when added to wires and delivery charges, produce savings for customers and profits for suppliers compared to the standard offer. Lower, rather than higher, wires charges better enable alternative suppliers an opportunity to meet this hurdle."[1]

Q IS THERE ANY EVIDENCE THAT CSPs ARE ACTIVELY COMPETING IN VIRGINIA'S RETAIL MARKETS?

A No. It is my understanding that there has been only limited competition in DVP's service territory and no competition in AEP's service territory. Without CSPs, there

[1]Staff Report in Case No. PUE010306, August 6, 2001, pages 12-13.

can be no *retail* competition. Absent a fundamental change in DVP's wires charges, which force CSPs to sell electricity below the prevailing wholesale market price, competitors will not enter the market. Thus, we will have wasted a golden opportunity to determine whether *retail* competition can work in the Commonwealth.

Q WHAT IS THE BASIS FOR YOUR CLAIM THAT USING WHOLESALE MARKETS TO DETERMINE THE PROJECTED PRICES FOR GENERATION WOULD ENABLE INCUMBENT ELECTRIC UTILITIES TO OVER-RECOVER THEIR STRANDED COSTS?

A DVP's methodology rests on the assumption that an incumbent utility should be made whole through wires charges if a customer purchases generation service from another supplier. In other words, the incumbent utility should be indifferent as to whether it recovers stranded costs through capped rates or wires charges.[2] This "make-whole" provision is designed to compensate the electric utility for lost revenues that it would incur if *retail* customers were to cease purchasing generation services from the incumbent. The "make-whole" approach implicitly but erroneously assumes that lost revenues are a proxy for stranded costs.

Lost revenues, however, are not the same as stranded costs. The make-whole provision, moreover, could enable a utility to potentially over-recover stranded costs through wires charges alone.

Q WHY ARE LOST REVENUES NOT THE SAME AS STRANDED COSTS?

A Lost revenue is defined as the incumbent's foregone sales revenue caused by the loss of a *retail* customer. There will be operating expenses, overhead costs, taxes and margins related to such foregone sales revenue. Some of these costs may not be incurred in a competitive environment, when the incumbent loses a retail

[2]Final Order in Case No. PUE010306, November 19, 2001 at 25.

customer. For example, in a competitive environment, if a generating unit is no longer cost-effective to operate because of prevailing market conditions, DVP would reduce operations or close the plant and thereby avoid incurring certain operating expenses. The lost revenue approach, which assumes a continuation of the status quo (i.e., no change in plant operations), is designed to compensate DVP for such costs through wires charges, even if the utility no longer incurs them.

Stranded costs, by contrast, are the difference between the market value of an incumbent electric utility's generation fleet and the corresponding book value, or embedded cost of the fleet. If the generation fleet has a higher book value than its associated market value, then stranded costs would be positive. The incumbent electric utility would have stranded benefits if the market value of its generation fleet were in excess of the corresponding book value. Thus, stranded costs exclude costs that are avoidable and are more closely related to the investment in generation capacity.

Q HOW IS THE MARKET VALUE OF AN INCUMBENT ELECTRIC UTILITY'S GENERATION FLEET DETERMINED?

A A determination of stranded costs is by definition a long-term multi-year analysis. The value of an incumbent electric utility's generation assets can be derived from the projected net revenue stream (i.e., future market revenues less cash operating costs) over the remaining useful lives of the utility's generating assets. This is in contrast to the lost revenue analysis, which is being used to set wires charges, that only considers the revenues derived from one type of wholesale market associated with displaced *retail* sales during the course of a year.

Q IF AN INCUMBENT ELECTRIC UTILITY WERE TO SUSTAIN LOST REVENUES IN THE EARLY YEARS OF A TRANSITION TO RETAIL COMPETITION, DOES IT FOLLOW THAT THE INCUMBENT UTILITY HAS STRANDED COSTS?

A No. A utility that sustains lost revenues during the transition to retail competition may not necessarily have stranded costs. This is shown in Exhibit ____ (JP-1). For purposes of this exhibit, I am using lost revenues as a proxy for stranded costs.

The starting point for Exhibit ___(JP-1) is DVP's determination of the embedded cost of generation (line 1, column 1) and the corresponding market price (line 1, column 2) for the GS-4 class. Lost revenue (column 3) is the difference between embedded costs and market price. If lost revenue is positive, then the wires charge (column 4) is the same as lost revenue. However, if lost revenue were negative, then the wires charge would be zero. The latter is based on the fact that the Virginia Electric Utility Restructuring Act prohibits "negative" wires charges.

I then projected the embedded costs and market prices over the long-term. These projections assume no increase in fuel costs. Further, I escalated embedded cost 1% per year. This is a conservative assumption since embedded costs should decrease over time as the existing generation fleet investment is depreciated.

The projected market price is based on an analysis of the incremental cost of new generation capacity, as shown in Exhibit ____ (JP-2). This analysis is based on the cost of installing combined-cycle gas turbine (CCGT) capacity in 2007; six months before the capped rates are lifted. In the interim, I assumed that market prices would gradually rise to the level that supports the addition of new generation capacity in 2007. This was also a conservative assumption since DVP requires new generation capacity to maintain its target planning reserve margin beginning in 2003.

I then quantified the net present value of both the embedded cost and market price for the period 2003-2030, which approximates the useful life of a CCGT. On a net present value basis, DVP would incur *negative* $39.66 per megawatthour (MWh) of lost revenue. However, based on the definition of the wires charge, it will have recovered *positive* $12.91 of wires charges. Thus, it would over recover its stranded costs by nearly $53 per MWh.

Q WHAT CONCLUSIONS CAN BE DRAWN FROM THE LOST REVENUE ANALYSIS SHOWN IN EXHIBIT ____ (JP-1)?

A The analysis reveals a changing relationship between embedded cost and market prices. Although market prices may be below embedded cost in the early years of a transition to *retail* competition, they may well exceed embedded cost over the vast majority of the remaining useful life of the generation fleet.

Thus, an incumbent electric utility that experiences lost revenues in the near term may not today have stranded costs. Therefore, no wires charge is needed to make the utility whole. The analysis shows, however, that making the incumbent whole for lost revenues, coupled with the prohibition of negative wires charges, virtually guarantees that the incumbent electric utility will over-recover its just and reasonable net stranded costs.

Q SHOULD THE COMMISSION ADDRESS THE POTENTIAL OVER-RECOVERY OF STRANDED COSTS BY INCUMBENT ELECTRIC UTILITIES?

A Yes. The Commission should docket a proceeding to investigate the stranded costs of each incumbent electric utility that proposes to implement a wires charge. The Commission should quantify such costs based on the value of the utility's generating assets over their remaining useful lives. If, as a result of this determination, it is clear that the utility does not have stranded costs, then there is no justification to impose wires charges on *retail* consumers that desire to competitively shop for their electricity provider.

Q WOULD IT BE FEASIBLE TO COMPLETE SUCH AN UNDERTAKING IN TIME TO SET WIRES RATES BY OCTOBER 1, 2002?

A No. Quantifying stranded costs for each of the incumbent electric utilities will take some time and effort on the part of the Commission and all interested stakeholders.

Q HOW CAN THE COMMISSION FACILITATE RETAIL COMPETITION NOW WHILE PROVIDING A REASONABLE OPPORTUNITY FOR INCUMBENT ELECTRIC UTILITIES TO RECOVER THEIR JUST AND REASONABLE NET STRANDED COSTS?

A The Commission should establish projected market prices for generation at *retail*. However, regardless of whether projected market prices are at *retail* or wholesale, they should be set to the level that will support the entry of new generation capacity in the Commonwealth. Reasonable market prices must reflect the value of both generation capacity and energy. Where capacity must be expanded in order to satisfy projected demand, the market price must reflect the all-in cost of new generation capacity.

Q WOULD DVP'S PROJECTED WHOLESALE MARKET PRICES FOR GENERATION SUPPORT NEW CAPACITY ADDITIONS?

A No. This is shown in Exhibit ____ (JP-3). The starting point for this analysis is the projected average market price for generation for DVP's *retail* customers. The latter price is shown in Exhibit ____ (JP-4).

I then assessed the economic characteristics of new CCGT capacity and quantified the capacity value that could be supported by the average market price. For this assessment, I assumed a range of natural gas prices, operation and maintenance (O&M) expenses and carrying charges. Three scenarios were projected: a *Low Cost* scenario (column 2), a *Base Case* scenario (column 3), and a *High Cost* scenario (column 4).

The capacity value for each of the three cost scenarios is derived using a range of capacity factors (lines 9-12). If the capacity value were below the cost of new construction (line 13), then it would not be sufficient to support new market entry. As can be seen, the capacity values, even under the most conservative *Low Cost* scenario, are well below the cost of constructing new capacity.

Q HOW WOULD THE MARKET PRICE HAVE TO BE ADJUSTED IN ORDER TO SUPPORT NEW ENTRY OF GENERATION CAPACITY?

A The market price would have to be increased so that the capacity value is reasonably close to the corresponding construction cost of new capacity. This analysis is shown in Exhibit ____ (JP-5).

As can be seen, under the *Base Case*, the average market price of generation would have to be increased to more than $43 per MWh in order to support the cost of new generation capacity. This represents an $11 per MWh increase in DVP's projected market price. In my opinion, market prices above $40 per MWh should provide more opportunities for *retail* customers to shop for a generation provider.

Q WOULD SETTING THE MARKET PRICE ABOVE $43 PER MWh GUARANTEE THAT COMPETITION WILL FLOURISH IN THE COMMONWEALTH?

A No. There are other institutional changes that must also occur to allow *retail* competition to flourish. The most significant of these changes is for the incumbent electric utilities to become full-fledged members of an operating regional transmission organization. Recently, both AEP and DVP revealed that they had signed memoranda of understanding to join the PJM RTO.

Q WHY ARE THESE OTHER CHANGES ALSO IMPORTANT TO ENSURE THAT RETAIL COMPETITION CAN FLOURISH IN THE COMMONWEALTH?

A As previously stated, CSPs will not enter the market unless there is a reasonable opportunity to sell electricity at *retail* at a price that will enable the CSP to recover not only its operating cost but also its marketing and administrative costs, while providing a reasonable return for its shareholders. Critical to this assessment is having a market structure and market protocols that are clear and understandable and which do not discriminate between the various market players.

Workably competitive markets should provide a platform conducive to support the entry of CSPs in fully competitive wholesale and *retail* markets. These changes, coupled with setting more realistic wires charges, will help to ensure that real and meaningful competition will occur in the five years remaining in the transition period.

<u>The Flaws with DVP's Projected Wholesale Market Prices</u>

Q WHAT IS THE BASIS FOR YOUR CONTENTION THAT DVP'S PROPOSED WHOLESALE MARKET PRICES UNDERSTATE THE VALUE OF ITS GENERATION FLEET?

A DVP's projected market prices were based solely on an analysis of energy futures' contracts that are being traded in forward wholesale markets. Specifically, DVP relied on two forward wholesale markets: PJM West and Cinergy.

Q WHAT TYPES OF WHOLESALE PRODUCTS IS DVP USING TO DETERMINE PROJECTED WHOLESALE PRICES IN BOTH THE PJM WEST AND CINERGY MARKETS?

A DVP is relying on the price of forward energy strip contracts reported by *Platts Energy Trader* and the *Intercontinental Exchange*. Energy strip contracts are equivalent to block power sales; that is, they reflect the sale of power at a constant rate (i.e., a 100% load factor).

Q ARE FORWARD ENERGY STRIPS THE ONLY MARKETS THAT DVP'S GENERATION FLEET CAN PARTICIPATE IN IF IT WERE TO SELL DISPLACED POWER?

A No. DVP can deploy its generation fleet in a variety of wholesale markets in addition to participating in long-term (e.g., monthly, quarterly) commodity markets. These other markets include short-term (e.g., hourly, daily, weekly) capacity and energy, ancillary services, energy balancing, shaping and risk management.

For example, DVP's fleet is comprised of resources that can either be brought on line in short notice (combustion turbines) or cycled to meet changes in demand (e.g., combustion turbines and combined-cycle units). These resources would be better suited to supporting short-term rather than long-term markets. In fact, the economics of combustion turbines make it highly unlikely that these units would be operated at a 100% load factor around the clock over the long-term, which is the market used by DVP to project generation prices. Given the existence of other market opportunities, it would be imprudent to deploy the fleet in only long-term forward energy markets.

Q YOU PREVIOUSLY STATED THAT DVP'S GENERATION FLEET COULD PROVIDE SHAPING. WHAT DO YOU MEAN BY SHAPING?

A Retail customers (or their CSPs) do not purchase electric power at a constant rate. Their load shapes are more cyclical in nature. Thus, even assuming that *retail* customers (or their CSPs) could accurately forecast their loads in advance, they would have to purchase electric power that reflected the cyclical shape of their load.

Supplying such load would be an ideal use for a generation fleet comprised of base load (to provide 100% load factor service), intermediate and peaking resources (that can provide cyclical and peaking services). In other words, DVP is ideally positioned to utilize its extensive generation fleet to provide a shaped product to *retail* load serving entities. This shaped product is a more valuable service than 100% load factor energy.

Q WHAT OTHER VALUE ADDED SERVICES CAN BE PROVIDED BY DVP'S GENERATION FLEET?

A An incumbent electric utility can use its generation fleet to provide risk management services. For example, by hedging fuel costs, DVP can provide price risk management to CSPs who are trying to gain market share by offering fixed price products to *retail* customers.

In addition to price risk management, *retail* customers also need a means of hedging volume risk. When a *retail* customer signs a contract with a competitive supplier, the supplier will purchase the power in the wholesale market to accommodate the projected needs of that *retail* customer. However, it is very difficult in practice for an individual *retail* customer to project his needs accurately. Risk adverse customers will ask their supplier to take this risk by establishing a "bandwidth" around its projected load. Thus, volume risk management is yet another value-added service that a wholesale generation provider can satisfy.

This is analogous to the "swing" service required by gas-fired generators. Because of their higher cost, gas units are typically dispatched after coal and nuclear units when additional capacity is required to meet demand. However, gas units may also be dispatched if either coal or nuclear units are forced out of service or due to other system conditions. Given this uncertainty, gas-fired generators will purchase both base load (to cover around the clock needs) and swing services (to cover incremental needs on short notice). By providing greater flexibility in an uncertain environment, swing service is more valuable to the customer and, thus, will command a premium over base load service.

Q DO YOU HAVE ANY OTHER CONCERNS REGARDING DVP'S USE OF FORWARD ENERGY MARKETS TO DERIVE THE PROJECTED MARKET PRICE OF GENERATION?

A Yes. As previously stated, DVP's projected market prices were developed from published forecasts of forward energy markets as published by *Platts Energy Trader* and *Intercontinental Exchange*. The use of published forward market prices is only valid if it can be demonstrated that these forward markets are liquid.

A liquid forward market can be characterized by the presence of many buyers and sellers that are actively engaged in trading in each of the forward markets that DVP relied upon to project prices. A list of the forward energy markets used by DVP in its market price analysis is shown in Exhibit ____ (JP-6).

Q HAVE YOU ANALYZED THE TRADING IN EACH OF THESE FORWARD MARKETS TO DETERMINE WHETHER ANY OR ALL OF THESE MARKETS ARE LIQUID?

A Yes. Exhibit ____ (JP-7) is an analysis of the trading volume in each of the forward energy contracts used by DVP to support its projected market prices. This data was obtained from the *Intercontinental Exchange*, and it represents actual transactions for the period July 24-30, 2002. The analysis shows both the average trading volume as well as the number of transactions that were closed during this trading period in two markets, PJM West (page 1) and Cinergy (page 2).

As can be seen, both the average trading volume and number of transactions are highly variable in the PJM West and Cinergy markets. There is considerably more trading (and thus liquidity) in the near-term market (August 2002) for PJM West and (August-September 2002) for Cinergy than in any of the other forward markets. In fact, both the trading volume and number of trades falls off dramatically in the fourth quarter of 2002 and in each of the 2003 forward markets that are currently trading. In some instances, the market price is based on only a handful of transactions.

The decline in liquidity – especially in the 2003 forward energy markets – is not surprising given the current state of energy trading. As the Commission is well aware, market manipulations as well as a serious decline in credit quality have prompted many energy traders to drastically reduce (and in some cases eliminate) their energy trading practice. Without confidence in the market and without credit worthy counter parties, it is no longer reasonable to assume that published prices for forward energy markets are representative of market conditions. This is confirmed by the evidence presented in Exhibit ____ (JP-7).

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is PO Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and am employed by BAI (Brubaker & Associates, Inc.).

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft.

Upon graduation, in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. BAI was formed in April 1995.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the procurement and management of utility and energy services in both regulated and competitive markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present timely seminars on electricity. In the last five years, BAI professionals have participated in numerous regulatory proceedings and in projects implementing customer choice in 40 states and Canada.

During my tenure at both DBA and BAI, I have also been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, and conducting site evaluation. Recent engagements have included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing request for proposals (RFPs), evaluating RFP responses and contract negotiation. I am also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over 20 states and in two Canadian provinces, and have testified before the regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

In addition to our main office in St. Louis, BAI also has branch offices in Denver, Colorado; Chicago, Illinois; Asheville, North Carolina; Kerrville, Texas; and Plano, Texas.

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